FIFTH ANNUAL LMOP CONFERENCE AND PROJECT EXPO

DECEMBER 12, 2001

BANKING ON THE GREEN POWER PREMIUM

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In discussing the current state of Green Power Premiums ("GPP" or "GPP's") in the United States, it is important to take a look back to the origins of GPP's, what was the impetus for their development and what impact did they have on the development of Green Power in this country.

The first of these GPP's were established as a result of the passage of the Public Utility Regulatory Policies Act ("PURPA") of 1979, where Congress, in response to the energy crisis of the early 1970's, passed PURPA which was designed to reduce U.S. dependence on foreign oil supplies by stimulating the development and construction of Qualifying Facilities ("QF's). PURPA, for the first time, required regulated utilities to purchase all the output from these independently owned (not utility owned) QF's at rates not less than the utility's own cost of produce (or acquire) the same amount of power (the "Avoided Cost"). PURPA sought to induce independent power producers ("IPP's") to develop both more efficient power plants, that produced both thermal and electrical power (Cogeneration Facilities "CGF"), and renewable power facilities (Small Power Production Facilities "SMPF").

In the early years subsequent to the passage of PURPA, QF projects were slow to develop. This was due primarily to two factors. First, the Avoided Cost of the utilities was a variable rate that fluctuated with such factors as time of day, time of year, overall electrical demand, fuel prices, etc. Without the certainty of a fixed rate, it was difficult for the QF's to obtain capital from the bank and institutional markets who did not have the ability, or desire, to predict the future Avoided Costs of the nation's utilities. Second, was the fact that Cogeneration and Small Power Production Facilities were more expensive to build and maintain than existing utility generation facilities. A fact that hasn't changed (except for degree) in the last 20 years.

Several progressive states, including California and New York, mandated that the regulated utilities operating in these states, offer IPP's Standard Offer contracts which provided the IPP with either a fixed energy rate ($ per Kw/hr) or a fixed capacity rate ($

per Kw of installed capacity) or both. It was reasoned that the rates offered were an estimation of the 10 to 20 year levelized cost to produce energy in the state by the state's utilities and therefore were a "prediction" of the Avoided Cost and the Federal Energy Regulatory Commission ("FERC") agreed. California offered a choice of several Standard Offer Contracts to the IPP's. The Standard Offer 4 Contract offered a 10 year fixed schedule for "as-delivered" energy (Kw's) which started in 1985 at around 8.4¢ Kw/hr and paid as high as 14.7¢ Kw/hr by the tenth year. This was the contract of choice for most SMPF's (renewable power projects). In addition California utilities offered the Standard Offer 2 contracts which provided a fixed Capacity Payment for 20 years of up to $236 per Kw/yr and a variable energy payment based on a formula which took into account inflation and fuel price fluctuation. The SO2 contract was favored by CGP's.

New York offered the much litigated "6¢" Contract (litigated by the investor owned utilities ("IOU's"). In addition, New Hampshire, Maine and Pennsylvania offered some innovative QF inducing contracts. It was widely known that in the states that favored IPP's and renewable power, that the state's public utility commission would make very aggressive assumptions as to the predicted future price of power (Avoided Cost estimate) and therefore be able to offer attractive fixed rate contracts to the IPP's. In states where the IOU's exercised significant influence over the public utility commissions, Avoided Cost predictions were low and thus thwarted the development of QF's. Generally the southern states and mid-western states saw little of no QF development.

As energy prices stabilized in the late 1980's and early 1990's, the pace of renewable energy project development declined. As a result, several private interest groups (coal, steel, wind) lobbied Congress to pass a series of Tax Credit measures which would promote the development of renewable energy through the issuance of tax credits associated with the production of such energy (Production Tax Credits "PTC's"). Congress adopted, and twice extended, Section 29 PTC's for Synthetic Fuel Projects. The Section 29 PTC nets the producer approx. $2.00 for each MM/Btu's of synthetic fuel produced during the first 10 years of project service. The Section 29 PTC has expired for projects placed in service after 1998. Due to what Congress believes was a " tax abuse" by synthetic fuel producers (coke batteries, steel blast furnaces and coal agglomeration projects), it is unlikely that Congress will re-authorize Section 29 in this session.

In addition to Section 29, Congress authorized Section 45 PTC's for wind power and later added Close Loop Biomass and Poultry Litter (though none of the latter category of projects have yet been built). Section 45 PTC's are worth approx. 1.5¢ Kw/hr and are available for the first ten years of power production. Section 45 PTC's are set to expire for projects placed in service after December 31, 2001. Currently, both the House and Senate Economic Stimulus Bills have Section 45 PTC extensions with the House extending the placed-in-service deadline through December 31, 2003, and the Senate through December 31, 2002. It is likely that the final ESB will extend the availability of the Section 45 PTC's.

In light of the move to state electric utility deregulation, California initiated a transitional support for renewables wherein a renewable energy producer would be able to "bid" for a cash support on a ¢ Kw/hr for production from a renewable source (State of California defined) for a period of two years after the state went to competitive pricing of power supplies. Renewable energy producers and the state conducted a "reverse" auction where producers bid a support price (which is in addition to the Avoided Cost paid by the utility) for the amount of energy they expected to produce. The state accepted the lowest bid prices first and moved up the price bids until all the money allocated by the legislature was allocated to the producers.

In early 1990's, Illinois passed the "Retail Rate" Law that required the state's utilities to pay the owners of "Qualified Solid Waste to Energy" projects, located in the state, the utility's "Retail Rate" for power deliveries. The project would receive the Retail Rate for ten years and at the end of ten years the project would repay (over the next ten years) the difference between the Retail Rate for energy delivered over the initial ten year period and the Avoided Cost Rate for those same ten years. In essence, the project received a ten year interest free loan for the difference between the Retail Rate and the Avoided Cost. This delta has been significant in the range of 4 to 6¢ Kw/hr in recent years. In the Illinois case, the state absorbed the costs of such program by allowing the state's utilities to deduct the "overpayment" (Retail Rate payment less Avoided Cost) paid to the producers from state franchise taxes due to the state. As is the case with current emission offsets and Carbon Credits, the Illinois Retail Rate "Green Premium" is a result of a state effort to reduce airborne pollution from landfills and not for the purposes of inducing the production of renewable energy.

Before we can begin to discuss the value of the "Green Premium", we first must consider the definition of "Green" power. Historically, Green power was defined by PURPA in the late 1970's. Green power was defined as the typical renewable power sources such as low head hydro, biomass, wind geothermal, solar photovoltaic, solar thermal, landfill gas and other waste fueled projects. In addition, PURPA sought to attach a "green" label on power projects which achieved a higher combustion efficiency such as cogeneration projects which achieve a 10 to 12% higher combustion efficiency that simple cycle processes.

Subsequent to the passage of PURPA and the authorization of Section 29 and 45 PTC's, it has been the individual states which have sought to define "Green" power. Given the historical premium cost nature of renewable power, many states which have passed competitive power choice legislation (so called deregulation), have included provisions to support renewable power. These provisions have ranged from simple consumer choice (allowing consumers the ability to purchase renewable power at whatever the price) to outright subsidies for renewable power providers.

By far, the vast majority of states adopting open choice have adopted Renewable Portfolio Standards ("RPS") to establish a demand for renewable power. The RPS requires that a certain percentage of the total power that a retail supplier supplies to the ratepayers in a given state be classified as "renewable". This standard varies from 1.2% (Connecticut) to 20% (Maine). The theory is, that any retail supplier in any given state with an RPS will be required to purchase enough renewable power to meet the standard in order to supply power in the state. It is assumed that this demand will produce premium pricing above fossil fueled power plants. For a variety of reasons I will discuss later in this paper, it has not worked out that way. Many factors are called into play when states adopt this RPS. These factors include the variety and amounts of renewable resources located in a state. A state with abundant hydro resources will most likely name hydropower among its renewable resources, those with little or no hydro resources are not likely to include hydropower as a renewable power source.

Political influence also plays a role in selecting renewable standards. In Connecticut, for instance, with United Technologies supplying over 50,000 direct and indirect jobs in the state, it was not unexpected the any project employing a fuel cell is considered "renewable" for the purposes of the state's RPS (International Fuel Cells the nation's largest manufacturer of industrial scale fuel cells is a subsidiary of UT). With these diverse standards it is now difficult to determine what is green and whether or not a project's power output would command a premium. Immediate questions which come to mind are whether the power sold by a project which is located in a state where the project qualifies as a renewable power source, would such power be considered "Green" if sold in another state where such resource is not considered "Green". Should a project's "Green" power attributes be considered based upon the state where it is produced or where it is sold? These questions need to be sorted out in order to make the RPS in the various states truly meaningful as a green premium to the producer.

Nationwide, there is an attempt to establish a national "Green" certification program for electric power production. This program is called Green-e ®. For now such certification is meaningful for consumers who may want to know the term "Green" (power) really means something, but worthless in terms of establishing a "Green" standard for all state RPS's. Green, for the purposes of state RPS, is a legislated matter and any changes in the Green definition for RPS must be approved in the individual state legislatures, something (because of significant political pressures) not easily accomplished.

So where do we go from here? A brief summary of what could be currently defined as Green Premiums is in order. On the Federal, level we still have Section 29 Tax Credits for projects placed in service prior to June 30, 1998, and a very uncertain future with regards to their re-authorization. We still have Section 45 PTC's for wind and poultry litter and prospects look good for an extension of at least one year. President Bush's National Energy Plan proposes a variety of incentives, including tax credits, for renewables. Low energy prices combined with the current war on terrorism has dampened any enthusiasm in Congress to push this plan forward. In light of the September 11, 2001, attack and the recent events in Israel, it puzzles me how Congress could ignore various legislative initiatives with the prospects of increasing the U.S. supply of renewable energy and lowering our dependence on foreign oil.

Based on my last count there were over 85 state sponsored renewable energy support programs throughout the United States and Puerto Rico. The incentive programs generally fall into three categories: Direct Subsidy, Tax Incentives and Market Support.

The Tax Incentive programs vary greatly from a tax credit for LFG projects in Maryland to an exemption from state and local property taxes in Washington State. The Illinois retail Rate Program is also considered a tax incentive program in that it involves a "transfer" of taxes otherwise due the state by the utility to the Qualified Solid Waste to Energy project in the form of the premium over the avoided cost (Retail Rate – Avoided Cost = Premium).

Currently, 17 states offer some form of Direct Subsidy to renewable energy producers which include grants, loans and investments in projects. Check with one of the LMOP representatives to get a list of the state programs. By far the most popular state incentive program for renewables, in those states which have adopted transition (or will transition in the future) to Retail Choice, is the mandated Renewable Portfolio Standard. Various States have mandated that each retail energy supplier in each state must supply a legislated amount of renewable energy of the total energy delivered by that supplier in that state. The amount varies by state with Connecticut being the smallest 1.5 % and Maine being the largest 20 %. The definition of "renewable" varies by state and what is renewable in one is not in the other. Several of the RPS programs are flawed in that not all retail suppliers in the state are required to meet the RPS. Connecticut for example, the "Default Provider" (the distribution utility) does not have to meet the RPS. In CT the Default Providers (Northeast Utilities and CT Light and Power) sell almost 99 % of the retail power sold in the state making the RPS non-effective and creating demand for renewable power in the state. In addition, the "California Crisis" this past winter has caused several states to delay the implementation of Retail Choice.

One of the potential Green Power Premiums not to be overlooked are those offered by various Municipal Utilities across the United States. Municipal electric utilities are not affected by the FERC decision in the California "Green Rate" case. In that decision FERC ruled that the State of California could not force the state's IOU's to purchase "Green" power at rates above the utility's avoided cost. This has prevented many states from attracting the green power that many citizens have demanded, and in many cases, voted for. This ruling is applicable to IOU's and not Municipal electric companies. Many environmentally friendly municipal electric companies have, and continue, to offer attractive "Green" rates in long term contracts. Both fixed rate and fixed "premium" (fixed margin above avoided cost) contracts have been offered. The municipal utility "Green" contract is currently one of the best PPA choices for Green Power Producers in the Country. Most Municipal electric companies offer the producer (and his Lender) a combination of "premium" predictable rates, long term and an acceptable credit risk profile.

In addition to Federal and State programs there exists, other exciting "Green" premiums that are rapidly becoming a reality. As a result of the Kyoto Treaty on Greenhouse Gases, a market has developed for the trading of greenhouse gas reduction credits or the so-called "Carbon Credits". I am not at all an expert on such Carbon Credits and I hope to learn much in tomorrow's sessions on the subject. But here is what I do know. Most of the industiralized nations have signed the Treaty except the U.S. The market for Carbon Credits is developing but cannot be considered a well developed market at this time. Basically, a renewable energy producer "creates" a Carbon Credit by either destroying a greenhouse gas (in the case of an LFG to energy project) or by displacing the greenhouse gas produced by energy producers burning fossil fuels by producing energy with reduced or no greenhouse gas production (wind power). By displacing the fossil fuel produced energy, the renewable energy producer creates a Carbon Credit equal to difference between the CO2 which would have been produced by the fossil fuel energy producer and the actual CO2 produced by the renewable energy producer for the actual energy generated.

This Carbon Credit is then sold to a producer of greenhouse gases allowing him to register a reduction in greenhouse gas production (through the purchase of the Carbon Credit) while not actually reducing his production of greenhouse gases. Most of the deals that have been done to date, have been in the form of options. In these option agreements the purchaser, for a relatively small price, purchases the "option" to purchase the Carbon Credits at a set price at a later date. This presents a problem for the green power producer in that it will be almost impossible to "monetize" any value in the Option Contract. We Lenders assume that the "option" will not be exercised.

There also have been "futures" contracts executed where purchasers have been obligated to purchase Carbon Credits in the future for Carbon Credits produced today. These contracts may be a challenge to the credit producer in that he must make sure that: one, the purchaser is a good credit risk and second, the obligation to purchase is absolutely "hell and high water". It would be very difficult for a credit producer to re-sell Carbon Credits which are under "contract" to a purchaser who is in or near bankruptcy (Enron) or who might be looking for a way to escape his obligation in the future (change of law, new Treaty amending Kyoto). It would be wise to require the purchaser to provide a Letter of Credit equal to his obligation under a "futures" Carbon Credit Contract.

In addition to Carbon Credits, certain other emission offsets might be available. To the extent the energy production from a Green Power project might displace the energy produced by fossil fuel combustion, you or your energy purchaser might be entitled to an emission offset credit. Currently there are well developed markets for both sulfur dioxide (SO2) offsets and nitrous oxide (NOX) offsets, both potent acid rain producing emissions. In certain "non-attainment" areas these emission offsets can be very valuable and it would be wise for the Green Energy producer to investigate the potential to structure the ownership of the green project (such that the emission producing energy purchaser has ownership in the project/emission offsets) to take advantage of these Green Premiums.

Last in the realm of "Green Premiums" are the Renewable Energy Certificates. Again, I am not an expert in this area and there is a session tomorrow on the subject. Simply put, a Renewable Energy Certificate or "Green Tag" is a certificate that certifies the "Green-ness" of a renewable energy project. The important question to ask in assessing the potential value of such a certificate is: What is green and to whom? The idea of Green Tags is to split the "Green-ness" of the power producing method or technology from the actual power, or electrons. The "Green-ness" is sold to one buyer and the electrons to another. The most likely potential value to such certificate is in association with the various state mandated RPS and state sponsored “Green” power incentive program. The current Green Tag marketplace is very new and not well defined. The prevailing question of what makes a project “green”, in many cases has not been answered. We know for example that an LFG to Energy project located in Connecticut is a Class 1 Renewable if it sells power in the state and that that power would qualify towards the satisfaction of the RPS for that retailer in the state. Would that project’s power qualify under the RPS if it were located in Pennsylvania and sold its power to a supplier in the state? The answer is no under current legislation. A project or technology that is defined as renewable in one state, may not be renewable in another and therein lies the fundamental problem with the Green Tags. Current and past legislation that created the RPS in most states, did not envision the separating of the “Green-ness” from the power produced and thus the legislation is either silent or unclear on matters relating to the Green tags.

A national organization has made an attempt to set criteria for establishing a nationwide green energy certification. This program is called Green-e®. This program has great potential to benefit the consumer who may wonder if what comes out of his electrical socket is actually produced by a Green technology but currently has little impact on the various state RPS or green incentive programs that have their own definition and certification programs. Green tags could offer a significant “Green” premium to producers of renewable energy which locate projects in states which possess the renewable resources but where no “Green” premium is available. In order to realize value from such Green Tags we need to work towards adopting a universal “Green Power” certification program which can be adopted by the various states and to amend the various state RPS, open choice and Green incentive legislation to accept Green Tags as a method to achieving their Green power objectives.

Now that we have defined what constitutes a Green Power Premium, we now need to address the issue of how to convert them to cash. If you are planning to develop and build a renewable energy project with 100% equity then you can skip the rest of this presentation, but if you are planning to leverage your investment with capital from a project finance lender, here are some helpful hints.

There are certain risks that are normally taken by project lenders and some that are not under any circumstances (no matter what the interest rate). Generally, project lenders are accustomed to taking production risk and that is the risk that a project can produce the quantity and quality of the product it was designed to produce. So, if your project is producing Kw’s or Btu’s a project lender will lend you money on the basis of the amount and the selling price for the Kw’s and Btu’s you expect to produce over the next 10 to 20 years. If your project also is receiving a Green Premium for each Kw or Btu produced, the lender, who is already taking production risk, will most likely loan on the basis of the incremental value of the Green Premium, but only if the payment of the premium is “Hell and High Water” and only subject to the creditworthiness of the premium provider. If the premium provider has any circumstances where he is not obligated to pay the Green Premium (change of law or regulation, tax risk etc.) then the lender will assume that the premium will not be paid. Lenders always take credit risk and so would be willing to assess the premium provider's ability to pay the premium in the future. If the premium provider is different from the power purchaser make sure the provider is creditworthy. If not, require that he post a Letter of Credit backing his obligation. Generally the lenders will require that your premium provider have the same creditworthiness as your power purchaser.

Lenders are becoming increasingly ready to accept price risk if historical markets exist for the product sold. Lenders are willing to take market price risk for electrical energy sales throughout the U.S. But don't be surprised if the lender assumes a market price equal to the market five-year low price, increasing at half the five-year average inflation rate. So if your premium is based upon a percentage of a market price for energy that can be assessed, a loan value can be determined. If your premium is based on the "average market premium paid for Green Power from 2002 to 2016 in the State of Iowa" then because of the relatively unknown nature and history of such market, lenders will not be willing to assess any value to such premium.

There are certain risks that lenders avoid and here are a few. Historically, many Green projects were financed through the monetization of tax credits (Section 29 and 45 Production Tax Credits). These Green Premiums were monetized by Lenders who looked to the "Tax Credit Purchaser's" Hell and High Water obligation to contribute a percentage of the value of the PTC. No lender, of which I am aware, was willing to take any tax risk associated with the tax structure of the transaction or the future obligation of the taxpayer to make contributions for PTC's. Most lenders required tax opinions (and many required Private Letter Rulings from the IRS) prior to monetizing the PTC's. No circumstance relieved the PTC purchaser's obligation to contribute money for the PTC's including tax status and change of law.

The change of law risk is something that no lender will knowingly take. In the case of the repeal of the Illinois Retail Rate Law benefits to waste burning facilities, lenders were taken by surprise by such actions and have been sensitized to such possibilities with respect to the repeal of Green Premiums by states (if you consider power from the Mass Burn Facility "Green"). Since this time, Lenders have had a heightened level of awareness to the level of "commitment" by states to Green Premiums.

In several states which have transitioned to Retail Choice by the mandating of a RPS, the IOU's and retail suppliers in those states have sought to pass the risk of repeal or deferral of the RPS to the Green producers in the Power Purchase Agreements ("PPA"). Soon after the passage of the RPS in Texas, several IOU's offered premium priced PPA's (approx. 5.0¢ Kw/hr) to Green Power Producers containing a clause stating that the fixed power rate would revert to the market rate if the State of Texas repealed or deferred the RPS. Several renewable energy projects were financed in the state under such PPA's but only on the basis of the projected "Market" prices for energy (approx 2.8¢ Kw/hr) and not based on 5.0¢ Kw/hr. Since the lower market rate assumption resulted in a loan value of less than half the amount of the higher fixed rate, several projects could not be completed. After much discussion with the utilities (and lack of any meaningful Green energy capacity additions) the utilities removed such clause from the PPA and absorbed the change of law risk, a risk rightfully theirs to take.

Likewise lenders are reluctant to take regulatory risk. PPA's which require the producer to take the risk that the state regulators will approve Green Premiums contained in the PPA or that revoke such Green premiums if the regulators do not allow the utility to pass such premiums through to the ratepayers will not be valued by lenders. In addition any Green Premium (Green Rates, Carbon Credits, emission offsets etc.) which is payable at the option of the purchaser will not be valued by lenders.

So how does the renewable project developer take advantage of current Green Premium offerings and what can he do to realize the benefits of future Green Premiums. First, would be to support the continuation and re-authorization of Production Tax Credits. With the possible exception of windpower (only in higher wind regimes), renewable energy cannot compete with the existing fossil fueled generation capacity burning $20 coal (a ton) and $3.00 gas (MM/Btu). So without incentives, new renewable projects will be slow to develop. By far the most significant Green Premium which has spurred the development of the vast majority of renewable energy capacity in this country has been the Federal Production Tax Credits in the form of Section 29 and 45 tax credits. They have been around for ten years and should remain available until renewable energy can compete with fossil fuels. We as individuals and as corporations should push for the continuation and re-authorization of PTC's **NOW !!!**

No other Green Premium has the ability to have such a major impact on new capacity additions. During times of high fossil fuels prices, scarcity and energy disruptions, the U.S. Congress has always been quick to promise energy independence through the development of renewable energy. But as soon as the prices fall, the gas lines disappear and the lights turn on with regularity, the promise of support for renewable energy fades like the glow of a spent candle. This is a very short sighted approach to a long term problem. Many European countries tax fossil fuels and transfer those taxes to the development of renewable energy. Germany currently produces 8% of its total power needs with renewables (not including hydro) and is well on its way to achieving 12% renewables by 2008. The U.S. produces less than 2% of its energy demand with non-hydro renewable energy. It is a national issue and should be solved by a national plan. Why not use the solution which has brought on-line that 2% of national renewable capacity, the PTC.

On the state level we should support the renewable energy incentives which work and change the ones which don't. Generally, state tax credit programs (both income and property tax abatements) do not provide enough incentive to bridge the difference between the cost to produce renewable energy and the market price for fossil fuel power. We should work on the state level for direct subsidies to bridge this price gap and be willing to give up the subsidy when market prices rise to sufficient levels to support renewable energy. If RPS are ever to work, we must be sure that the RPS applies to all providers in a given state and that the term "Renewable" is universal between states.

If RPS are going to work on a national scale we need to support Customer Choice Programs at the state level. Recent history has proven that retail customers are willing to pay a premium for green power but until the various states allow customer choice, they cannot buy the green energy until legislation opens up the retail market for energy. Many states have repealed or postponed the move to retail choice due to the California Crisis. We need to take the message to the states which have wavered in their retail choice decision that the California Crisis was caused by flawed legislation and not by a flawed concept of consumer choice. On the individual and corporate basis we should push for the Green Power choice if it is available in our state. Currently, Customer Choice is our best hope for Premium priced PPA's.

Before the California Crisis and resulting financial demise of the State's IOU's caused the collapse of the retail choice market in California, Green power customers enjoyed relatively stable rates. The energy price rise in California was caused primarily by the shortage of fossil fueled capacity and a sharp rise in natural gas prices. Green retailers had contracted sufficient Green energy capacity to serve their customer demand at mostly fixed prices. The events which pushed other power prices up, did not effect the costs to Green power retailers and did not contribute to the financial downfall of the IOU's. We as consumers and producers of power should realize that renewable power has the ability to provide long term stable pricing for energy (the very same predictability we need in our PPA's) and we should seek to match that ability to the need for such energy price stability within the retail consumer market….exploit our capabilities which other power producers cannot.

In my experience in Connecticut, few developers of renewable projects take advantage of the Renewable/Clean Energy Funds which many states have. States have money to spend. They know that their investment in renewable projects will attract additional investment in the Project and in the state. Project developers should investigate what programs are available and take advantage of them.

Green power producers must seek non-IOU Green Power incentive programs from municipal utilities. Put pressure on the utilities to add Green power to the mix if they currently do not. Extol the virtues of Green power and its inherent ability to add stability to future energy costs. Along with customer choice, support Green power purchases by municipal utilities. They represent the best opportunities to obtain premium priced PPA's.